HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 22, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2014

or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from__________ to__________

Commission File Number 001-32936
HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	95–3409686 (I.R.S. Employer Identification No.)
3505 West Sam Houston Parkway North Suite 400 Houston, Texas (Address of principal executive offices)	77043 (Zip Code)

(281) 618–0400
(Registrant's telephone number, including area code)

NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [√] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [√] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [√]	Accelerated filer [ ]	Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [√]

As of October 17, 2014, 105,537,973 shares of common stock were outstanding.

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 546,529	$ 478,200
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $5,971 and $2,234, respectively	125,718	156,925
Unbilled revenue	71,366	25,732
Costs in excess of billing	11,111	1,508
Current deferred tax assets	26,342	51,573
Other current assets	48,006	29,709
Total current assets	829,072	743,647
Property and equipment	2,129,058	1,963,706
Less accumulated depreciation	(488,871)	(431,489)
Property and equipment, net	1,640,187	1,532,217
Other assets:		
Equity investments	152,588	157,919
Goodwill	62,839	63,230
Other assets, net	60,270	47,267
Total assets	$ 2,744,956	$ 2,544,280
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 117,280	$ 72,602
Accrued liabilities	85,969	96,482
Income tax payable	25,588	760
Current maturities of long-term debt	24,394	20,376
Total current liabilities	253,231	190,220
Long-term debt	529,281	545,776
Deferred tax liabilities	267,409	265,879
Other non-current liabilities	17,592	18,295
Total liabilities	1,067,513	1,020,170
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,531 and 105,640 shares issued, respectively	936,922	933,507
Retained earnings	773,319	586,232
Accumulated other comprehensive loss	(32,798)	(20,688)

Total controlling interest shareholders' equity		1,677,443		1,499,051
Noncontrolling interests		—		25,059
Total equity		1,677,443		1,524,110
Total liabilities and shareholders' equity	$	2,744,956	$	2,544,280

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)
(in thousands, except per share amounts)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013
Net revenues	$ 340,837	$ 220,117
Cost of sales	214,590	150,660
Gross profit	126,247	69,457
Gain on disposition of assets	—	15,812
Selling, general and administrative expenses	(19,916)	(22,610)
Income from operations	106,331	62,659
Equity in earnings of investments	508	857
Net interest expense	(3,856)	(6,585)
Loss on early extinguishment of long-term debt	—	(8,572)
Other income, net	598	2,366
Other income – oil and gas	1,837	1,681
Income before income taxes	105,418	52,406
Income tax provision	29,832	7,058
Net income from continuing operations	75,586	45,348
Income from discontinued operations, net of tax	—	44
Net income, including noncontrolling interests	75,586	45,392
Less net income applicable to noncontrolling interests	—	(799)
Net income applicable to Helix	$ 75,586	$ 44,593
Basic earnings per share of common stock:		
Continuing operations	$ 0.72	$ 0.42
Discontinued operations	—	—
Net income per common share	$ 0.72	$ 0.42
Diluted earnings per share of common stock:		
Continuing operations	$ 0.71	$ 0.42
Discontinued operations	—	—
Net income per common share	$ 0.71	$ 0.42
Weighted average common shares outstanding:		
Basic	104,997	105,029
Diluted	105,338	105,136

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)
(in thousands, except per share amounts)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net revenues	$ 899,996	$ 649,724
Cost of sales	588,765	460,203
Gross profit	311,231	189,521
Loss on commodity derivative contracts	—	(14,113)
Gain on disposition of assets, net	10,418	14,727
Selling, general and administrative expenses	(69,614)	(65,041)
Income from operations	252,035	125,094
Equity in earnings of investments	709	2,150
Net interest expense	(12,856)	(28,252)
Loss on early extinguishment of long-term debt	—	(12,100)
Other expense, net	(229)	(1,884)
Other income – oil and gas	15,709	5,781
Income before income taxes	255,368	90,789
Income tax provision	67,778	16,078
Net income from continuing operations	187,590	74,711
Income from discontinued operations, net of tax	—	1,073
Net income, including noncontrolling interests	187,590	75,784
Less net income applicable to noncontrolling interests	(503)	(2,365)
Net income applicable to Helix	$ 187,087	$ 73,419
Basic earnings per share of common stock:		
Continuing operations	$ 1.77	$ 0.68
Discontinued operations	—	0.01
Net income per common share	$ 1.77	$ 0.69
Diluted earnings per share of common stock:		
Continuing operations	$ 1.77	$ 0.68
Discontinued operations	—	0.01
Net income per common share	$ 1.77	$ 0.69
Weighted average common shares outstanding:		
Basic	105,038	105,036
Diluted	105,374	105,152

The accompanying notes are an integral part of these condensed consolidated financial statements.

5

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)
(in thousands)

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
Net income, including noncontrolling interests	$	75,586	$	45,392
Other comprehensive income (loss), net of tax:				
Unrealized gain (loss) on hedges arising during the period		(9,209)		1,117
Reclassification adjustments for loss included in net income		812		396
Income taxes on unrealized (gain) loss on hedges		2,939		(529)
Unrealized gain (loss) on hedges, net of tax		(5,458)		984
Foreign currency translation gain (loss)		(15,706)		11,311
Other comprehensive income (loss), net of tax		(21,164)		12,295
Comprehensive income		54,422		57,687
Less comprehensive income applicable to noncontrolling interests		—		(799)
Comprehensive income applicable to Helix	$	54,422	$	56,888

	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
Net income, including noncontrolling interests	$	187,590	$	75,784
Other comprehensive loss, net of tax:				
Unrealized loss on hedges arising during the period		(9,283)		(16,050)
Reclassification adjustments for loss included in net income		2,080		900
Income taxes on unrealized loss on hedges		2,521		5,303
Unrealized loss on hedges, net of tax		(4,682)		(9,847)
Foreign currency translation gain (loss)		(7,428)		12
Other comprehensive loss, net of tax		(12,110)		(9,835)
Comprehensive income		175,480		65,949
Less comprehensive income applicable to noncontrolling interests		(503)		(2,365)
Comprehensive income applicable to Helix	$	174,977	$	63,584

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)
(in thousands)

	Nine Months Ended September 30,	
	2014	2013
Cash flows from operating activities:		
Net income, including noncontrolling interests	$ 187,590	$ 75,784
Adjustments to reconcile net income, including noncontrolling interests, to net cash provided by (used in) operating activities:		
Income from discontinued operations, net of tax	—	(1,073)
Depreciation and amortization	81,274	71,542
Amortization of deferred financing costs	3,653	4,091
Stock-based compensation expense	5,711	7,297
Amortization of debt discount	4,149	3,850
Deferred income taxes	24,728	(23,911)
Excess tax from stock-based compensation	(120)	(168)
Gain on disposition of assets, net	(10,418)	(14,727)
Loss on early extinguishment of debt	—	12,100
Unrealized loss and ineffectiveness on derivative contracts, net	69	140
Changes in operating assets and liabilities:		
Accounts receivable, net	(16,496)	2,046
Other current assets	(19,388)	7,904
Income tax payable	25,440	(37,806)
Accounts payable and accrued liabilities	26,083	(46,313)
Oil and gas asset retirement costs	(956)	(9,886)
Other noncurrent, net	(9,758)	(561)
Net cash provided by operating activities	301,561	50,309
Net cash used in discontinued operations	—	(30,503)
Net cash provided by operating activities	301,561	19,806
Cash flows from investing activities:		
Capital expenditures	(204,528)	(275,935)
Distributions from equity investments, net	5,041	6,110
Proceeds from sale of assets	11,074	189,054
Acquisition of noncontrolling interests	(20,085)	—
Net cash used in investing activities	(208,498)	(80,771)
Net cash provided by discontinued operations	—	582,965
Net cash provided by (used in) investing activities	(208,498)	502,194
Cash flows from financing activities:		
Early extinguishment of Senior Unsecured Notes	—	(281,490)
Borrowings under revolving credit facility	—	47,617
Repayment of revolving credit facility	—	(147,617)
Repurchase of Convertible Senior Notes due 2025	—	(3,487)
Proceeds from term loans	—	300,000
Repayment of term loans	(11,250)	(370,931)

Repayment of MARAD borrowings	(5,376)	(5,120)
Deferred financing costs	(3,143)	(10,948)
Distributions to noncontrolling interests	(1,018)	(3,059)
Repurchases of common stock	(8,538)	(5,562)
Excess tax from stock-based compensation	120	168
Exercise of stock options, net and other	—	95
Proceeds from issuance of ESPP shares	3,223	2,711
Net cash used in financing activities	(25,982)	(477,623)
Effect of exchange rate changes on cash and cash equivalents	1,248	(1,296)
Net increase in cash and cash equivalents	68,329	43,081
Cash and cash equivalents:		
Balance, beginning of year	478,200	437,100
Balance, end of period	$ 546,529	$ 480,181

The accompanying notes are an integral part of these condensed consolidated financial statements.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 — Basis of Presentation and Recent Accounting Standards

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its wholly- and majority-owned subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its wholly- and majority-owned subsidiaries. All material intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission (the “SEC”), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles (“U.S. GAAP”) and are consistent in all material respects with those applied in our 2013 Annual Report on Form 10-K (“2013 Form 10-K”). The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. We have made all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that we believe are necessary for a fair presentation of the condensed consolidated balance sheets, statements of operations, statements of comprehensive income, and statements of cash flows, as applicable. The operating results for the three- and nine-month periods ended September 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014. Our balance sheet as of December 31, 2013 included herein has been derived from the audited balance sheet as of December 31, 2013 included in our 2013 Form 10-K. These unaudited condensed consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and notes thereto included in our 2013 Form 10-K.

Certain reclassifications were made to previously-reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606).” This ASU provides a single five-step approach to account for revenue arising from contracts with customers. The ASU requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance is effective prospectively for annual reporting periods beginning after December 15, 2016, including interim periods. Early adoption is not permitted. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption through a cumulative adjustment. We are currently evaluating which transition approach to use and the potential impact the adoption of this new standard may have on our consolidated financial statements.

Table of Contents

Note 2 — Company Overview

Our Operations

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on well intervention and robotics operations. We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We provide services primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our "life of field" services are segregated into four business segments: Well Intervention, Robotics, Subsea Construction and Production Facilities (Note 11). Our Subsea Construction segment was significantly diminished following the sale of substantially all of our assets related to this reportable segment during 2013 and early 2014 (see Note 2 to our 2013 Form 10-K and Note 2 to our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2014). Our Production Facilities segment includes the Helix Producer I ("HP I") vessel (which we now own 100% after acquiring our minority partner's noncontrolling interests in the entity that owns the vessel for $20.1 million in February 2014) as well as our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") (Note 5). The Production Facilities segment also includes the Helix Fast Response System ("HFRS"), which provides certain operators access to our Q4000 and HP I vessels in the event of a well control incident in the Gulf of Mexico.

Discontinued Operations

In February 2013, we sold Energy Resource Technology GOM, Inc. ("ERT"), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico, for $624 million plus additional consideration in the form of overriding royalty interests in ERT's Wang well and certain exploration prospects. As a result, we have presented the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying condensed consolidated financial statements. See Note 3 to our 2013 Form 10-K for additional information regarding our discontinued operations and Note 6 regarding the use of a portion of the sale proceeds to reduce our indebtedness under our former credit agreement.

Note 3 — Details of Certain Accounts

Other current assets and other assets, net consist of the following (in thousands):

	September 30, 2014	December 31, 2013
Note receivable (1)	$ 10,000	$ —
Other receivables	840	785
Prepaid insurance	9,613	7,038
Other prepaids	15,969	12,999
Spare parts inventory	2,429	1,038
Value added tax receivable	9,120	7,589
Other	35	260
Total other current assets	$ 48,006	$ 29,709

	September 30, 2014	December 31, 2013
Note receivable (1)	$ 20,000	$ —

Deferred dry dock expenses, net		14,249		20,833
Deferred financing costs, net (Note 6)		24,077		24,297
Intangible assets with finite lives, net		654		622
Other		1,290		1,515
Total other assets, net	$	60,270	$	47,267

9

Table of Contents

(1) Relates to the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014. Interest on the note is payable quarterly at a rate of 6% per annum. A $10 million principal reduction is required to be paid on each December 31 of 2014, 2015 and 2016.

Accrued liabilities consist of the following (in thousands):

	September 30, 2014		December 31, 2013	
Accrued payroll and related benefits	$	55,613	$	50,527
Current asset retirement obligations		742		2,024
Unearned revenue		6,490		19,608
Billing in excess of cost		—		1,677
Accrued interest		1,362		4,187
Derivative liability (Note 15)		5,917		2,651
Taxes payable excluding income tax payable		7,918		4,811
Pipelay assets sale deposit		—		5,000
Other		7,927		5,997
Total accrued liabilities	$	85,969	$	96,482

Note 4 — Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of three months or less. The following table provides supplemental cash flow information (in thousands):

	Nine Months Ended September 30,			
	2014		2013	
Interest paid, net of interest capitalized	$	11,671	$	39,754
Income taxes paid	$	53,390	$	78,408

Our non-cash investing activities include accruals for property and equipment capital expenditures. These non-cash investing accruals totaled $21.3 million and $9.5 million as of September 30, 2014 and December 31, 2013, respectively. Additionally, $30 million of our non-cash investing activities relates to the promissory note we received in connection with the sale of our Ingleside spoolbase in January 2014 (Note 3).

Note 5 — Equity Investments

As of September 30, 2014, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (“Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $82.4 million and $85.8 million as of September 30, 2014 and December 31, 2013, respectively (including capitalized interest of $1.2 million and $1.3 million at September 30, 2014 and December 31, 2013, respectively).

Independence Hub, LLC. In December 2004 we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $70.2 million and $72.1 million as of September 30, 2014 and December 31, 2013, respectively (including capitalized interest of $4.0 million and $4.3 million at September 30, 2014 and December 31, 2013, respectively).

Table of Contents

We received the following distributions from these equity investments (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Deepwater Gateway	$500	$1,600	$4,250	$5,100
Independence Hub	200	800	1,500	3,160
Total	$700	$2,400	$5,750	$8,260

Note 6 — Long-Term Debt

Scheduled maturities of our long-term debt outstanding as of September 30, 2014 are as follows (in thousands):

	Term Loan	MARAD Debt	2032 Notes (1)	Total
Less than one year	$18,750	$5,644	$—	$24,394
One to two years	30,000	5,926	—	35,926
Two to three years	30,000	6,222	—	36,222
Three to four years	30,000	6,532	—	36,532
Four to five years	172,500	6,858	—	179,358
Over five years	—	63,610	200,000	263,610
Total debt	281,250	94,792	200,000	576,042
Current maturities	(18,750)	(5,644)	—	(24,394)
Long-term debt, less current maturities	262,500	89,148	200,000	551,648
Unamortized debt discount (2)	—	—	(22,367)	(22,367)
Long-term debt	$262,500	$89,148	$177,633	$529,281

(1) Beginning in March 2018, the holders of our Convertible Senior Notes due 2032 may require us to repurchase these notes or we may at our option elect to repurchase these notes. The notes will mature in March 2032.

(2) Our Convertible Senior Notes due 2032 will increase to their face amount through accretion of non-cash interest charges through March 2018.

Included below is a summary of certain components of our indebtedness:

Credit Agreement

In June 2013, we entered into a Credit Agreement (the “Credit Agreement”) with a group of lenders pursuant to which we borrowed $300 million under the Credit Agreement’s term loan (the “Term Loan”) component and may borrow revolving loans (the “Revolving Loans”) and/or obtain letters of credit under a revolving credit facility up to an outstanding amount of $600 million (the “Revolving Credit Facility”). Subject to customary conditions, we may request an increase of up to $200 million in aggregate commitments with respect to the Revolving Credit Facility, additional term loans or a combination thereof. The $300 million we borrowed under the Term Loan was in connection with our early redemption of the remaining $275 million Senior Unsecured Notes outstanding in July 2013 (see “Senior Unsecured Notes” below).

The Term Loan and the Revolving Loans (together, the “Loans”) will bear interest, at our election, in relation to either the base rate established by Bank of America N.A. or to a LIBOR rate, provided that all Swing Line Loans (as defined in the Credit Agreement) will be base rate loans. The Term Loan currently bears interest at the one-month LIBOR rate plus 2.25%. In September 2013, we entered into various interest rate swap contracts to fix the one-month LIBOR rate on $148.1 million of the Term Loan. The fixed LIBOR rates were between 74 and 75 basis points.

Table of Contents

The Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 1.00% to 2.00%. The Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 2.00% to 3.00%. A letter of credit fee is payable by us equal to our applicable margin for LIBOR rate Loans multiplied by the daily amount available to be drawn under outstanding letters of credit. Margins on the Loans will vary in relation to the consolidated coverage ratio, as provided by the Credit Agreement. We currently also pay a fixed commitment fee of 0.375% on the unused portion of our Revolving Credit Facility. At September 30, 2014, our availability under the Revolving Credit Facility totaled $583.2 million, net of $16.8 million of letters of credit issued.

The Term Loan is repayable in scheduled principal installments of 5% in each of the initial two loan years ($15 million per year), and 10% in each of the remaining three loan years ($30 million per year), payable quarterly, with a balloon payment of $180 million at maturity. These installment amounts are subject to adjustment for any prepayments on the Term Loan. We may elect to prepay amounts outstanding under the Term Loan without premium or penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without premium or penalty, and may reborrow any available amounts paid up to the amount of the Revolving Credit Facility. The Loans mature on June 19, 2018. In certain circumstances, we will be required to prepay the Loans.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the “Loan Documents”) include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries’ ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, pay dividends and incur capital expenditures. In addition, the Credit Agreement obligates us to meet certain financial ratios, including the Consolidated Interest Coverage Ratio and the Consolidated Leverage Ratio (as defined in the Credit Agreement). We have designated five of our foreign subsidiaries, and may designate any newly established foreign subsidiaries, as subsidiaries that are not generally subject to the covenants in the Credit Agreement (the “Unrestricted Subsidiaries”), provided we meet certain liquidity requirements, in which case EBITDA of the Unrestricted Subsidiaries is not included in the calculations with respect to our financial covenants. Our obligations under the Credit Agreement are guaranteed by our wholly-owned domestic subsidiaries (except Cal Dive I – Title XI, Inc.) and Canyon Offshore Limited. Our obligations under the Credit Agreement, and of the guarantors under their guaranty, are secured by most of our assets and assets of the guarantors and Canyon Offshore Limited, plus pledges of up to two-thirds of the shares of certain foreign subsidiaries.

Convertible Senior Notes Due 2032

In March 2012, we completed a public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032 (the “2032 Notes”). The net proceeds from the issuance of the 2032 Notes were $195.0 million after deducting the underwriter’s discounts and commissions and offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of our 3.25% Convertible Senior Notes due 2025 in separate, privately negotiated transactions (see Note 7 to our 2013 Form 10-K for additional information). The remaining net proceeds were used for general corporate purposes, including the repayment of other indebtedness.

The 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March 15, 2032 unless earlier converted, redeemed or repurchased. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the Indenture governing the 2032 Notes.

Table of Contents

Prior to March 20, 2018, the 2032 Notes are not redeemable. On or after March 20, 2018, we, at our option, may redeem some or all of the 2032 Notes in cash, at any time upon at least 30 days' notice, at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. In addition, the holders of the 2032 Notes may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the Indenture governing the 2032 Notes).

In connection with the issuance of the 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting rules. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date upon which the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception.

MARAD Debt

This U.S. government guaranteed financing (the "MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures in February 2027. The MARAD Debt is collateralized by the Q4000, is guaranteed 50% by us, and initially bore interest at a floating rate that approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date.

Nordea Credit Agreement

In September 2014, our wholly-owned subsidiary, Helix Q5000 Holdings S.à r.l. ("Q5000 Holdings"), entered into a Credit Agreement (the "Nordea Credit Agreement") with a syndicated bank lending group for a term loan (the "Nordea Term Loan") in an amount of up to $250 million. The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000, which is currently estimated in early 2015. The parent company of Q5000 Holdings, Helix Vessel Finance S.à r.l., has guaranteed the Nordea Term Loan. The loan will be secured by the Q5000 and its charter earnings as well as by a pledge of the shares of Q5000 Holdings. This indebtedness is nonrecourse to Helix.

The Nordea Term Loan will bear interest at a LIBOR rate plus a margin of 2.5%, with an undrawn fee of 0.875%. The Nordea Term Loan matures five years after funding and is repayable in scheduled principal installments of $8.9 million, payable quarterly, with a balloon payment of $80.4 million at maturity. Installment amounts are subject to adjustment for any prepayments on this debt. Q5000 Holdings may elect to prepay amounts outstanding under the Nordea Term Loan without premium or penalty, but may not reborrow any amounts prepaid. In certain circumstances, Q5000 Holdings will be required to prepay the loan.

The Nordea Credit Agreement and the other related loan documents include terms and conditions, including covenants, that are considered customary for this type of transaction. The covenants include restrictions on Q5000 Holdings's ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets, and pay dividends. In addition, the Nordea Credit Agreement obligates Q5000 Holdings to meet minimum financial requirements, including liquidity, consolidated debt service coverage and collateral maintenance.

Table of Contents

Former Credit Facility

Similar to our current Credit Agreement, our former credit facility contained both term loan and revolving loan components. This indebtedness was scheduled to mature on July 1, 2015. In February 2013, we repaid $318.4 million of borrowings outstanding under this former credit facility with the proceeds from the sale of ERT. We fully repaid the remaining indebtedness outstanding under this credit facility in June 2013. In connection with the repayments of this debt, we recorded charges totaling $3.5 million to accelerate a pro rata portion of the deferred financing costs associated with our former term loan debt. This charge is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying condensed consolidated statement of operations for the nine-month period ended September 30, 2013.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (the "Senior Unsecured Notes"). We had $275 million of the Senior Unsecured Notes outstanding at the beginning of 2013. We fully redeemed these notes in July 2013 (see Note 7 to our 2013 Form 10-K). Our results of operations for the three- and nine-month periods ended September 30, 2013 included a loss on early extinguishment of debt totaling $8.6 million in connection with the redemption of these notes.

Other

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 30, 2014, we were in compliance with these covenants.

Unamortized deferred financing costs are included in "Other assets, net" in the accompanying condensed consolidated balance sheets and are amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs (in thousands):

	September 30, 2014			December 31, 2013		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loan (matures June 2018) (1)	$ 3,638	$ (909)	$ 2,729	$ 3,638	$ (364)	$ 3,274
Revolving Credit Facility (matures June 2018) (1)	13,275	(3,319)	9,956	13,275	(1,327)	11,948
2032 Notes (mature March 2032)	3,759	(1,609)	2,150	3,759	(1,148)	2,611
MARAD Debt (matures February 2027)	12,200	(6,101)	6,099	12,200	(5,736)	6,464
Nordea Term Loan	3,143	—	3,143	—	—	—
Total deferred financing costs	$ 36,015	$ (11,938)	$ 24,077	$ 32,872	$ (8,575)	$ 24,297

(1)

Relates to amounts allocated to the existing Term Loan and Revolving Credit Facility, which became effective in June 2013.

The following table details the components of our net interest expense (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013 (1)
Interest expense	$8,952	$9,416	$24,474	$35,971
Interest income	(2,741)	(271)	(4,113)	(903)
Capitalized interest	(2,355)	(2,560)	(7,505)	(6,816)
Net interest expense	$3,856	$6,585	$12,856	$28,252

14

Table of Contents

(1) Interest expense amount includes $2.8 million for the three-month period ended March 31, 2013 that was allocated to ERT and is included in discontinued operations. Following the sale of ERT in February 2013, we ceased allocating interest expense to ERT, which then constituted a discontinued operation.

Note 7 — Income Taxes

The effective tax rates for the three- and nine-month periods ended September 30, 2014 were 28.3% and 26.5%, respectively. The effective tax rates for the three- and nine-month periods ended September 30, 2013 were 13.5% and 17.7%, respectively. The variance is primarily attributable to projected year-over-year increases in profitability in the United States and the 2013 tax benefit of a reduction in the U.K. statutory tax rate.

Income taxes have been provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items that are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate from continuing operations are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Statutory rate	35.0 %	35.0 %	35.0 %	35.0 %
Foreign provision	(7.2)	(12.3)	(7.8)	(11.8)
Tax return to accrual adjustment	—	(4.0)	—	(2.3)
Change in U.K. tax rate	—	(5.6)	—	(3.3)
Other	0.5	0.4	(0.7)	0.1
Effective rate	28.3 %	13.5 %	26.5 %	17.7 %

In June 2014, the U.S. Internal Revenue Service (“IRS”) and the Joint Committee on Taxation completed the examination procedures including all appeals and administrative reviews that the taxing authorities are required and expected to perform for the 2006 through 2010 audit period. In September 2014, we received an income tax refund in the amount of $35.2 million that was pending the conclusion of the examination. The refund was primarily attributable to the utilization of a net operating loss carryback from 2010.

Note 8 — Accumulated Other Comprehensive Income (Loss) (“OCI”)

The components of Accumulated OCI are as follows (in thousands):

	September 30, 2014	December 31, 2013
Cumulative foreign currency translation adjustment	$ (18,125)	$ (10,697)
Unrealized loss on hedges, net (1)	(14,673)	(9,991)
Accumulated other comprehensive loss	$ (32,798)	$ (20,688)

(1) Amounts relate to foreign currency hedges for the Grand Canyon, the Grand Canyon II and the Grand Canyon III charters as well as interest rate swap contracts for the Term Loan, and are net of deferred income taxes totaling $7.9 million and $5.4 million as of September 30, 2014 and December 31, 2013, respectively (Note 15).

15

Table of Contents

Note 9 — Earnings Per Share

We have shares of restricted stock issued and outstanding, which currently are unvested. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding unrestricted common stock and the shares are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss, we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

The presentation of basic EPS amounts on the face of the accompanying condensed consolidated statements of operations is computed by dividing the net income applicable to Helix common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (income) and denominator (shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying condensed consolidated statements of operations are as follows (in thousands):

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 75,586		$ 44,593	
Less: Income from discontinued operations, net of tax	—		(44)	
Net income from continuing operations	75,586		44,549	
Less: Undistributed income allocable to participating securities – continuing operations	(392)		(337)	
Net income applicable to common shareholders – continuing operations	$ 75,194	104,997	$ 44,212	105,029
Discontinued operations:				
Income from discontinued operations, net of tax	$—	104,997	$44	105,029
Diluted:				
Continuing operations:				
Net income applicable to common shareholders – continuing operations	$75,194	104,997	$44,212	105,029
Effect of dilutive securities:				
Share-based awards other than participating securities	—	341	—	107
Undistributed income reallocated to participating securities	1	—	—	—
Net income applicable to common shareholders – continuing operations	$75,195	105,338	$44,212	105,136

Discontinued operations:

Income from discontinued operations, net of tax	$—	105,338	$44	105,136

Table of Contents

	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
	Income	Shares	Income	Shares
Basic:				
Continuing operations:				
Net income applicable to Helix	$ 187,087		$ 73,419	
Less: Income from discontinued operations, net of tax	—		(1,073)	
Net income from continuing operations	187,087		72,346	
Less: Undistributed income allocable to participating securities – continuing operations	(980)		(525)	
Net income applicable to common shareholders – continuing operations	$ 186,107	105,038	$ 71,821	105,036
Discontinued operations:				
Income from discontinued operations, net of tax	$—		$1,073	
Less: Undistributed income allocable to participating securities – discontinued operations	—		(8)	
Net income applicable to common shareholders – discontinued operations	$—	105,038	$1,065	105,036
Diluted:				
Continuing operations:				
Net income applicable to common shareholders – continuing operations	$186,107	105,038	$71,821	105,036
Effect of dilutive securities:				
Share-based awards other than participating securities	—	336	—	116
Undistributed income reallocated to participating securities	3	—	—	—
Net income applicable to common shareholders – continuing operations	$186,110	105,374	$71,821	105,152
Discontinued operations:				
Income from discontinued operations, net of tax	$—	105,374	$1,073	105,152

No diluted shares were included for the 2032 Notes for the three- and nine-month periods ended September 30, 2014 and 2013 as the conversion trigger of $32.53 per share were not met in either period, and because we have the right to settle any such future conversions in cash at our sole discretion (Note 6).

Note 10 — Employee Benefit Plans

Long-Term Incentive Stock-Based Plans

As of September 30, 2014, there were 6.4 million shares available for issuance under our long-term incentive stock-based plans (the "LTI Stock Plans"). During the nine-month period ended September 30, 2014, the following grants of other share-based awards were made to executive officers and non-employee members of our Board of Directors under our LTI Stock Plans:

Grant Date
Fair Value

Date of Grant	Shares	Per Share	Vesting Period
January 2, 2014 (1)	73,609	$ 23.18	33% per year over three years
January 2, 2014 (2)	73,609	$ 26.79	100% on January 1, 2017
January 2, 2014 (3)	2,724	$ 23.18	100% on January 1, 2016
April 1, 2014 (3)	4,051	$ 22.98	100% on January 1, 2016
July 1, 2014 (3)	3,397	$ 26.31	100% on January 1, 2016

(1) Reflects the grant of restricted shares to our executive officers.

Table of Contents

(2) Reflects the grant of performance share units ("PSUs") to our executive officers. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors elects to pay in cash.

(3) Reflects the grant of restricted shares to certain members of our Board of Directors who have made an election to take their quarterly fees in stock in lieu of cash.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three- and nine-month periods ended September 30, 2014, $1.7 million and $5.2 million, respectively, were recognized as stock-based compensation expense related to share-based awards as compared with $1.6 million and $6.7 million for the three- and nine-month periods ended September 30, 2013. A total of $1.3 million of the stock-based compensation expense for the nine-month period ended September 30, 2013 was included within our discontinued operations.

Long-Term Incentive Cash Plans

We have certain long-term incentive cash plans (the "LTI Cash Plans") that provide long-term cash-based compensation to eligible employees. Cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). These are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of our Board of Directors at the time of the award. Cash payments under the LTI Cash Plans are made each year on the anniversary date of the award. Cash awards granted since 2012 have a vesting period of three years while those granted prior to 2012 have a vesting period of five years. The LTI Cash Plans are considered liability plans and as such are re-measured to fair value each reporting period with corresponding changes in the liability amount being reflected in our results of operations.

The cash awards granted under the LTI Cash Plans to our executive officers and selected management employees totaled $8.9 million in 2014 and $8.4 million in 2013. Total compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans was $5.4 million ($2.4 million related to our executive officers) for the nine-month period ended September 30, 2014. Overall, compensation expense recorded for the three-month period ended September 30, 2014 was immaterial reflecting the effect the decrease in our stock price at the end of September 2014 had on the value of our liability plan. For the three- and nine-month periods ended September 30, 2013, total compensation expense associated with the cash awards issued pursuant to the LTI Cash Plans was $3.3 million ($2.1 million related to our executive officers) and $7.5 million ($4.4 million related to our executive officers), respectively. The liability balance for the cash awards issued under the LTI Cash Plans was $10.5 million at September 30, 2014 and $14.8 million at December 31, 2013, including $6.7 million at September 30, 2014 and $11.1 million at December 31, 2013 associated with the cash awards issued to our executive officers under the LTI Cash Plans.

Employee Stock Purchase Plan

We also have an employee stock purchase plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance, of which 1.2 million shares were available for issuance as of September 30, 2014. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.3 million and $0.7 million for the three-and nine-month periods ended September 30, 2014, respectively. For the three- and nine-month periods ended September 30, 2013, share-based compensation with respect to the ESPP was $0.2 million and $0.6 million, respectively.

Table of Contents

For more information regarding our employee benefit plans, including our stock-based compensation plans, our long-term incentive cash plans and our employee stock purchase plan, see Note 9 to our 2013 Form 10-K.

Note 11 — Business Segment Information

We have four business segments: Well Intervention, Robotics, Subsea Construction and Production Facilities. Our Well Intervention segment includes our vessels and related equipment that are used to perform well intervention services primarily in the Gulf of Mexico and North Sea regions. Our well intervention vessels include the Q4000, the Helix 534, the Seawell, the Well Enhancer and the Skandi Constructor, which is a chartered vessel. We are currently constructing two additional well intervention vessels, the Q5000 and the Q7000. We have also contracted to charter two newbuild vessels, which are expected to be delivered in 2016 and used in connection with our contracts to provide well intervention services offshore Brazil. Our Robotics segment currently operates four chartered vessels, and also includes remotely operated vehicles (“ROVs”), trenchers and ROVDrills designed to complement offshore construction and well intervention services. We have sold substantially all of the assets associated with our former Subsea Construction operations, including the sale in January 2014 of our Ingleside spoolbase. The Production Facilities segment includes the HP I as well as our equity investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method. All material intercompany transactions between the segments have been eliminated. In February 2013, we sold ERT and as a result, the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment are presented as discontinued operations in the accompanying consolidated financial statements. See Note 3 to our 2013 Form 10-K for additional information regarding our discontinued operations.

We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments, most notably the majority of our cash and cash equivalents. Certain financial data by reportable segment is summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net revenues —				
Well Intervention	$205,139	$114,238	$546,057	$319,893
Robotics	131,707	90,370	339,301	242,940
Subsea Construction	—	4,120	358	69,305
Production Facilities	24,184	24,366	71,373	68,933
Intercompany elimination	(20,193)	(12,977)	(57,093)	(51,347)
Total	$340,837	$220,117	$899,996	$649,724
Income (loss) from operations —				
Well Intervention	$80,789	$33,544	$194,297	$93,906
Robotics	28,397	16,392	60,415	28,991
Subsea Construction (1)	41	15,088	10,871	29,031
Production Facilities	11,284	14,136	33,127	39,964
Corporate and other	(14,283)	(16,522)	(45,625)	(64,260)
Intercompany elimination	103	21	(1,050)	(2,538)
Total	$106,331	$62,659	$252,035	$125,094
Equity in earnings of equity investments	$508	$857	$709	$2,150

(1) Amount in 2014 includes the $10.5 million gain on the sale of our Ingleside spoolbase in January 2014. Amounts in 2013 include the $1.1 million loss on the sale of the Caesar in June 2013 and the $15.6 million gain on the sale of the Express in July 2013.

Table of Contents

Intercompany segment revenues are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Well Intervention	$8,635	$4,784	$22,052	$15,052
Robotics	11,558	8,193	35,041	31,305
Subsea Construction	—	—	—	317
Production Facilities	—	—	—	4,673
Total	$20,193	$12,977	$57,093	$51,347

Intercompany segment profits (losses), which only relate to intercompany capital projects, are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Well Intervention	$(87)	$(45)	$(236)	$(91)
Robotics	28	67	1,417	2,602
Subsea Construction	—	—	—	158
Production Facilities	(44)	(43)	(131)	(131)
Total	$(103)	$(21)	$1,050	$2,538

Segment assets are comprised of all assets attributable to each reportable segment. Corporate and other includes all assets not directly identifiable with our business segments, most notably the majority of our cash and cash equivalents. The following table reflects total assets by reportable segment (in thousands):

	September 30, 2014	December 31, 2013
Well Intervention	$ 1,503,592	$ 1,245,229
Robotics	324,101	282,373
Subsea Construction	32,959	38,054
Production Facilities	469,374	495,829
Corporate and other	414,930	482,795
Total	$ 2,744,956	$ 2,544,280

Note 12 — Commitments and Contingencies and Other Matters

Commitments

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. The vessel is expected to be completed and placed in service in early 2015. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects. The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000 (Note 6). At September 30, 2014, our total investment in the Q5000 was $282.0 million, including $231.9 million of scheduled payments made to the shipyard.

In February 2013, we contracted to charter the Grand Canyon II and Grand Canyon III for use in our robotics operations. The terms of the charters will be five years from the respective delivery dates, both of which are expected to be in 2015.

Table of Contents

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This $346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016. At September 30, 2014, our total investment in the Q7000 was $95.7 million, including the $69.2 million paid to the shipyard upon signing the contract.

In February 2014, we entered into agreements with Petróleo Brasileiro S.A. ("Petrobras") to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. At September 30, 2014, our total investment in the topside equipment for the two vessels was $31.0 million.

Contingencies and Claims

Under the terms of the equity purchase agreement for the sale of ERT, we required the buyer to provide bonding in a sufficient amount as determined by the Bureau of Ocean Energy Management (the "BOEM") to cover the decommissioning costs of ERT's lease properties and thus to replace and allow for a discharge of our existing guaranty to the BOEM for ERT's lease obligations. The buyer posted the bonding required by the equity purchase agreement, and we submitted a formal request to the BOEM to terminate and release our guaranty. On July 24, 2014, we received a letter from the BOEM terminating the period of liability under our guaranty effective July 14, 2014.

Litigation

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff made claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers, and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of the Company's then executive officers who are defendants. The defendants filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on our Board of Directors as required by Minnesota law, (ii) filed proper verification, or (iii) stated a claim. In August 2014, the judge in this case granted the defendants' motion to dismiss and dismissed the case with prejudice.

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Note 13 — Allowance for Uncollectible Accounts

The following table sets forth the activity in our allowance for uncollectible accounts since December 31, 2013 (in thousands):

Balance at December 31, 2013	$2,234
Provision (1)	5,196
Write-offs	(1,459)
Balance at September 30, 2014	$5,971

(1) Reflects charges associated with the provision for uncertain collection of a portion of our existing trade receivables related to our Robotics segment.

Table of Contents

Note 14 — Fair Value Measurements

Certain of our financial assets and liabilities are measured and reported at fair value on a recurring basis as required under applicable accounting requirements. These requirements establish a hierarchy for inputs used in measuring fair value. The fair value is to be calculated based on assumptions that market participants would use in pricing assets and liabilities and not on assumptions specific to the entity. The statement requires that each asset and liability carried at fair value be classified into one of the following categories:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).

(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments. The following table provides additional information related to other financial instruments measured at fair value on a recurring basis at September 30, 2014 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Interest rate swaps	$ —	$ 578	$ —	$ 578	(c)
Liabilities:					
Fair value of long-term debt (2)	513,278	104,300	—	617,578	(a)
Foreign exchange contracts	—	22,490	—	22,490	(c)
Interest rate swaps	—	662	—	662	(c)
Total net liability	$ 513,278	$ 126,874	$ —	$ 640,152	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative. See Note 15 for further discussion on fair value of our derivative instruments.

Table of Contents

(2) See Note 6 for additional information regarding our long-term debt. The value of our long-term debt is as follows (in thousands):

	September 30, 2014	
	Carrying Value	Fair Value (b)
Term Loan (matures June 2018)	$ 281,250	$ 278,438
2032 Notes (mature March 2032) (a)	200,000	234,840
MARAD Debt (matures February 2027)	94,792	104,300
Total debt	$ 576,042	$ 617,578

(a) Carrying value excludes the related unamortized debt discount of $22.4 million at September 30, 2014.

(b) The estimated fair value of all debt, other than the MARAD Debt, was determined using Level 1 inputs using the market approach. The fair value of the MARAD Debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other governmental obligations in the marketplace with similar terms. The fair value of the MARAD Debt was estimated using Level 2 fair value inputs using the market approach.

Note 15 — Derivative Instruments and Hedging Activities

Our operations are exposed to market risk associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in the accompanying condensed consolidated balance sheets at fair value.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that the hedges are effective. These fair value changes are recorded as a component of Accumulated OCI (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of changes in the fair value of cash flow hedges is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

For additional information regarding our accounting for derivatives, see Notes 2 and 16 to our 2013 Form 10-K.

Interest Rate Risk

From time to time, we enter into interest rate swaps to stabilize cash flows related to our long-term debt subject to variable interest rates. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of Accumulated OCI until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial for all periods presented. In September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan (Note 6). These monthly contracts began in October 2013 and extend through October 2016.

Table of Contents

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds and Norwegian kroner.

In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts that were not accounted for as hedge contracts have been settled. We had no foreign currency exchange contracts for vessel charters denominated in British pounds as of September 30, 2014.

Quantitative Disclosures Related to Derivative Instruments

As a result of the announcement in December 2012 of the sale of ERT, we de-designated all of our then remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our former credit agreement (Note 6), we were required to use a portion of the proceeds from the sale of ERT, as well as the sale of the Caesar and Express vessels, to make payments to reduce our indebtedness. Because of the probability that the former term loan debt would be totally repaid before the expiration of our then existing interest rate swaps, we also concluded that those swaps no longer qualified as cash flow hedges. The mark-to-market adjustments related to our commodity derivative contracts and interest rate swaps are reflected in “Loss on commodity derivative contracts” and “Other expense, net,” respectively, in the accompanying condensed consolidated statements of operations.

The following table presents the fair value and balance sheet classification of our derivative instruments that were not designated as hedging instruments (in thousands):

	September 30, 2014		December 31, 2013	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Foreign exchange contracts	Other current assets	$—	Other current assets	$69
		$—		$69

The following table presents the fair value and balance sheet classification of our derivative instruments that were designated as hedging instruments (in thousands):

	September 30, 2014		December 31, 2013	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Interest rate swaps	Other assets, net	$578	Other assets, net	$446
		$578		$446
Liability Derivatives:				
Foreign exchange contracts	Accrued liabilities	$5,255	Accrued liabilities	$1,905

Interest rate swaps	Accrued liabilities	662	Accrued liabilities	746
Foreign exchange contracts	Other non-current liabilities	17,235	Other non-current liabilities	13,166
		$23,152		$15,817

Table of Contents

Ineffectiveness associated with our derivatives was immaterial for all periods presented. The following tables present the impact that derivative instruments designated as cash flow hedges had on our Accumulated OCI (net of tax) and our condensed consolidated statements of operations (in thousands). We estimate that as of September 30, 2014 $3.8 million of unrealized losses in Accumulated OCI associated with our derivatives is expected to be reclassified into earnings within the next 12 months.

	Gain (Loss) Recognized in OCI on Derivatives, Net of Tax (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Foreign exchange contracts	$ (5,713)	$ 1,186	$ (4,823)	$ (9,645)
Interest rate swaps	255	(202)	141	(202)
	$ (5,458)	$ 984	$ (4,682)	$ (9,847)

	Location of Gain (Loss) Reclassified from Accumulated OCI into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Earnings (Effective Portion)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2014	2013	2014	2013
Interest rate swaps	Net interest expense	$ (215)	$ —	$ (646)	$ —
Foreign exchange contracts	Cost of sales	(597)	(396)	(1,434)	(900)
		$ (812)	$ (396)	$ (2,080)	$ (900)

The following table presents the impact that derivative instruments not designated as hedges had on our condensed consolidated statements of operations (in thousands):

	Location of Gain (Loss) Recognized in Earnings on Derivatives	Gain (Loss) Recognized in Earnings on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2014	2013	2014	2013
Oil and natural gas commodity contracts	Loss on commodity derivative contracts	$ —	$ —	$ —	$ (14,113)
Interest rate swaps	Other expense, net	—	—	—	(86)
Foreign exchange contracts	Other expense, net	—	498	7	(693)
		$ —	$ 498	$ 7	$ (14,892)

Table of Contents

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

This Quarterly Report on Form 10-Q contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward-looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements included herein or incorporated herein by reference that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potential," "should," "cou terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which are subject to change;
- statements relating to the construction, upgrades or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of the Q5000 and the Q7000 and the construction of two chartered vessels that are expected to be delivered in 2016 and used in connection with our contracts to provide well intervention services offshore Brazil (Note 12);
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

Although we believe that the expectations reflected in these forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- impact of domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery or chartering of new vessels for our well intervention and robotics fleet, including the Q5000 (expected in 2015), the Q7000 (expected in 2016), the Grand Canyon II and the Grand Canyon III (both expected in 2015);
- unexpected delays in the delivery of the two newbuild chartered vessels to be used to perform contracted well intervention work in Brazil (both expected in 2016);

- unexpected future capital expenditures (including the amount and nature thereof);
- the effectiveness and timing of completion of our vessel upgrades and major maintenance items;
- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;

Table of Contents

- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our current and future hedging activities;
- the long-term availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those described in Item 1A. "Risk Factors" in our 2013 Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

Executive Summary

Business Strategy

We are an international offshore energy services company that provides specialty services to the offshore energy industry, with a focus on our well intervention and robotics operations. For several years since 2008 we were focused on improving our balance sheet and increasing our liquidity through dispositions of non-core business assets and the related repayment of a significant portion of our indebtedness. We substantially finalized this process with the sale of ERT in February 2013, the sale of our two remaining pipelay vessels in mid-year 2013, and the sale of our Ingleside spoolbase in January 2014. As such, we believe that we are now positioned for growth and expansion in our well intervention and robotics operations.

Our focus is on expanding our well intervention and robotics businesses. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. Our well intervention fleet has expanded with the addition of the Helix 534, which was placed in service in February 2014. Our well intervention fleet will further expand following the completion of the two newbuild semi-submersible vessels currently under construction, the Q5000 and the Q7000, and the expected delivery in 2016 of two newbuild monohull vessels which we will charter in connection with the well intervention service agreements that we entered into with Petrobras in February 2014. In addition, we are expanding our robotics operations by acquiring additional ROVs and trenchers as well as chartering two newbuild ROV support vessels, the Grand Canyon II and the Grand Canyon III, both of which are expected to be delivered in 2015.

OneSubsea LLC, a Cameron and Schlumberger company, Helix and Schlumberger Technology Corporation announced in August 2014 that a letter of intent was entered into to form an alliance to develop technologies and deliver services to optimize the cost and efficiency of subsea well intervention systems. Upon agreement of the final terms of the alliance definitive agreement, the alliance will leverage the capabilities of Helix, OneSubsea and Schlumberger, to provide a unique, fully integrated offering to clients, combining marine support with well access and control technologies.

Economic Outlook and Industry Influences

Demand for our services is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. The performance of our business is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

Table of Contents

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- regional conflicts and economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by the Organization of Petroleum Exporting Countries;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the exploration and production of shale oil and natural gas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- domestic and international tax policies.

The global price for oil has declined significantly since mid-year 2014 based on concerns over excess supply coupled with a slowing global economic outlook. The trading price for crude oil on the New York Mercantile Exchange fell below $80 per barrel in October 2014 for the first time since June 2012. Many analysts currently predict that oil prices may decrease further through 2015. The decrease in oil prices may be partially attributable to a global supply and demand imbalance which reflects both increased production in certain countries, primarily in the United States reflecting the effect fracking has had on domestic production and a general weakening in the global economic that has primarily affected both Europe and Asia. Any additional news suggesting weak or declining economic data could affect global equity and commodity markets, which could affect normal business activities. Weaker global equity and commodity markets could potentially reduce investment in offshore oil and gas capital projects, which may affect rates that drilling rig contractors can charge for their services. We believe that capital would be less likely to be expended on the beginning of offshore projects, for example for exploration drilling projects, than on projects that span the life of an oil and gas field’s production. Our Well Intervention and Robotics operations are intended to service the life span of an oil and gas field as well as to provide abandonment services at the end of the life of a field as required by governmental regulations. Thus over the longer term, we believe that fundamentals for our business remain favorable as the need for continual replenishment of oil and gas production is the primary driver of demand for our services.

In addition, we believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) an increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) an increasing number of subsea developments.

Helix Fast Response System

We developed the HFRS as a culmination of our experience as a responder in the Macondo well control and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are currently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who executed utilization agreements with us that specified the day rates to be charged should the HFRS be deployed in connection with a well control incident. The original set of agreements expired on March 31, 2013, and we entered into a new set of substantially similar agreements with the operators who formed HWCG LLC, a Delaware limited liability company comprised of some of the original CGA members as well as other industry participants, to perform the same functions as CGA with respect to the HFRS. These new agreements became effective April 1, 2013, and have a four-year term.

Table of Contents

RESULTS OF OPERATIONS

We have four business segments: Well Intervention, Robotics, Subsea Construction and Production Facilities. Our Subsea Construction activities have significantly diminished following the sale of substantially all of our remaining assets related to this reportable segment, including the sale of our Ingleside spoolbase in January 2014. Previously, we had an additional business segment, Oil and Gas. In February 2013, we completed the sale of ERT (Note 2). Accordingly, the results of ERT are presented as discontinued operations for the three- and nine-month periods ended September 30, 2013 in this Quarterly Report on Form 10-Q.

All material intercompany transactions between the segments have been eliminated in our condensed consolidated financial statements, including our consolidated results of operations.

Continuing Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. We operate primarily in deepwater in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. In addition, our Robotics operations are often contracted for the development of renewable energy projects (wind farms). As of September 30, 2014, our services had backlog of $2.4 billion, including $162.5 million expected to be performed over the remainder of 2014. The substantial majority of our backlog is associated with our Well Intervention business segment. As of September 30, 2014, our well intervention backlog was $2.1 billion, including $94.1 million expected to be performed over the remainder of 2014. This includes a five-year contract with BP to provide well intervention services with our Q5000 semi-submersible vessel once its construction is completed (expected in 2015) and four-year agreements with Petrobras to provide well intervention services offshore Brazil with two chartered newbuild monohull vessels (both expected to be placed in service in 2016). Backlog contracts are cancelable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our services as contracts may be added, canceled and in many cases modified while in progress.

Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as a numerical measure of a company’s historical or future performance, financial position, or cash flows that includes or excludes amounts from the most directly comparable measure under U.S. GAAP. We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required by our debt covenants. We believe our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA as net income from continuing operations plus income taxes, depreciation and amortization expense, and net interest expense and other. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense and thus is added back to net income from continuing operations.

In the following reconciliation, we provide amounts as reflected in our accompanying condensed consolidated financial statements unless otherwise footnoted. This means that these amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA from continuing operations, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and the gain or loss on disposition of assets from continuing operations.

Table of Contents

Other companies may calculate their measures of EBITDA and Adjusted EBITDA differently than we do, which may limit their usefulness as comparative measures. Because EBITDA is not a financial measure calculated in accordance with U.S. GAAP, it should not be considered in isolation or as a substitute for net income attributable to common shareholders or cash flows from operations, but used as a supplement to these GAAP financial measures. The reconciliation of our net income from continuing operations to EBITDA from continuing operations and Adjusted EBITDA from continuing operations is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income from continuing operations	$75,586	$45,348	$187,590	$74,711
Adjustments:				
Income tax provision	29,832	7,058	67,778	16,078
Net interest expense and other	3,258	4,219	13,085	30,136
Loss on early extinguishment of long-term debt	—	8,572	—	12,100
Depreciation and amortization	28,421	21,850	81,274	71,542
EBITDA from continuing operations	137,097	87,047	349,727	204,567
Adjustments:				
Noncontrolling interests	—	(1,037)	(661)	(3,078)
Gain on disposition of assets, net	—	(15,812)	(10,418)	(14,727)
ADJUSTED EBITDA from continuing operations	$137,097	$70,198	$338,648	$186,762

Comparison of Three Months Ended September 30, 2014 and 2013

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Three Months Ended September 30,		Increase/
	2014	2013	(Decrease)
Net revenues —			
Well Intervention	$ 205,139	$ 114,238	$ 90,901
Robotics	131,707	90,370	41,337
Subsea Construction	—	4,120	(4,120)
Production Facilities	24,184	24,366	(182)
Intercompany elimination	(20,193)	(12,977)	(7,216)
	$ 340,837	$ 220,117	$ 120,720
Gross profit —			
Well Intervention	$ 84,166	$ 36,406	$ 47,760
Robotics	31,457	19,685	11,772
Subsea Construction	43	(335)	378
Production Facilities	11,422	14,287	(2,865)
Corporate and other	(944)	(607)	(337)
Intercompany elimination	103	21	82
	$ 126,247	$ 69,457	$ 56,790
Gross margin —			

Well Intervention	41	%	32	%
Robotics	24	%	22	%
Subsea Construction	N/A		(8	)%
Production Facilities	47	%	59	%
Total company	37	%	32	%

Table of Contents

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
Number of vessels (1) / Utilization (2)				
Well Intervention vessels	5/97	%	4/84	%
ROVs	63/78	%	57/68	%
Robotics vessels	6/90	%	5/98	%
Subsea Construction vessels	N/A		N/A	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in each category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues are as follows (in thousands):

		Three Months Ended September 30, 2014		2013		Increase/ (Decrease)
Well Intervention	$	8,635	$	4,784	$	3,851
Robotics		11,558		8,193		3,365
	$	20,193	$	12,977	$	7,216

Intercompany segment profit is as follows (in thousands):

		Three Months Ended September 30, 2014		2013		Increase/ (Decrease)
Well Intervention	$	(87)	$	(45)	$	(42)
Robotics		28		67		(39)
Production Facilities		(44)		(43)		(1)
	$	(103)	$	(21)	$	(82)

In reviewing the discussion below of our results of operations, please refer to the tables above and Note 11 for supplemental information regarding our business segment results. This discussion specifically refers to our Well Intervention, Robotics and Production Facilities segments. We sold our remaining Subsea Construction pipelay vessels in mid-year 2013.

Net Revenues. Our total net revenues increased by 55% for the three-month period ended September 30, 2014 as compared to the same period in 2013. The increase in net revenues in the comparable year over year periods reflects the addition of the Helix 534 to our Well Intervention fleet in February 2014 and the increased number of assets and asset utilization within our Robotics segment.

Our Well Intervention revenues increased by 80% for the three-month period ended September 30, 2014 as compared to the same period in 2013 primarily reflecting the Helix 534 being placed in service in the Gulf of Mexico in February 2014, and increased revenues in the North Sea region reflecting the Skandi Constructor being placed in service in 2013 and performing a high revenue project offshore Canada during the three-month period ended September 30, 2014. Our vessels had near full utilization (97%) during the third quarter of 2014 as compared to 84% utilization in the same period last year, with this lower utilization reflecting downtime for the Skandi Constructor as the vessel underwent modifications prior commencing well intervention service in September 2013.

Table of Contents

Robotics revenues increased by 46% for the three-month period ended September 30, 2014 as compared to the same period in 2013. The increase primarily reflects the addition of five ROVs and one trencher to our fleet, the higher utilization of our ROVs and trenchers, and 197 additional days of spot vessel utilization. Our trenching activities, primarily conducted in the North Sea region, have significantly increased during 2014 as compared to the unusually weak market that was experienced in 2013.

Our Production Facilities revenues remained relatively unchanged.

Gross Profit. Our total gross profit increased by 82% for the three-month period ended September 30, 2014 as compared to the same period in 2013. The gross profit associated with our Well Intervention segment increased by 131% for the three-month period ended September 30, 2014 as compared to the same period in 2013 primarily reflecting the addition of the Helix 534 to our fleet in February 2014 and the Skandi Constructor being fully utilized in well intervention operations during the three-month period ended September 30, 2014 as compared to approximately 30 days of utilization during the same period in 2013.

The gross profit associated with our Robotics segment increased by 60% for the three-month period ended September 30, 2014 as compared to the same period in 2013. The variance primarily reflects increased utilization for our ROVs and trenching assets. Utilization for our trenching assets increased significantly reflecting the resumption of trenching projects in the North Sea region following an unusually weak year for that work in 2013.

The gross profit related to our Production Facilities segment decreased by 20% for the three-month period ended September 30, 2014 as compared to the same period in 2013. The decrease primarily reflects the amortization of the deferred regulatory dry dock costs for the HP I that were incurred during the fourth quarter of 2013.

Gain on Disposition of Assets. The $15.8 million gain on disposition of assets for the three-month period ended September 30, 2013 primarily reflects the sale of the Express in July 2013.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses decreased by $2.7 million for the three-month period ended September 30, 2014 as compared to the same period in 2013. The decrease primarily reflects a $2.3 million net recovery of amounts previously drawn on a letter of credit associated with a completed international well abandonment project that were previously assessed as uncollectible in 2012.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $0.3 million for the three-month period ended September 30, 2014 as compared to the same period in 2013. The decrease primarily reflects lower revenues for both Deepwater Gateway and Independence Hub reflecting lower production at the fields being processed at each facility.

Net Interest Expense. Our net interest expense totaled $3.9 million for the three-month period ended September 30, 2014 as compared to $6.6 million for the same period in 2013. The decrease primarily reflects a reduction in interest expense and an increase in interest income partially offset by a decrease in capitalized interest. The decrease in interest expense reflects the reduction in our indebtedness with a higher interest rate mainly as a result of our redemption in July 2013 of the remaining $275 million of our Senior Unsecured Notes then outstanding. Interest income totaled $2.7 million for the three-month period ended September 30, 2014 as compared to $0.3 million for the same period in 2013. The amount of interest income for the third quarter of 2014 includes $2.1 million from an IRS income tax refund (Note 7) and $0.5 million on the promissory note held in connection with the sale of our Ingleside spoolbase (Note 3). Capitalized interest totaled $2.4 million for the third quarter of 2014 as compared to $2.6 million for the third quarter of 2013. Generally, our capitalized interest will be increasing as the construction of our vessels and related equipment progresses.

Loss on Early Extinguishment of Long-term Debt. The $8.6 million loss in the third quarter of 2013 was associated with our redemption of the remaining $275 million Senior Unsecured Notes then outstanding. The loss reflects the $6.5 million call premium and the acceleration of the remaining $2.1 million of unamortized deferred financing fees related to the original issuance of the Senior Unsecured Notes.

Table of Contents

Other Income, Net. We reported net other income of $0.6 million for the three-month period ended September 30, 2014 as compared to $2.4 million for the same period in 2013. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. The foreign exchange gains were attributed to the weakening of the U.S. dollar against other global currencies. Included in these foreign exchange gains was $0.5 million of gains related to our foreign exchange forward contracts in the three-month period ended September 30, 2013 (Note 15).

Other Income – Oil and Gas. The $0.2 million increase for the three-month period ended September 30, 2014 as compared to the same period in 2013 was primarily associated with higher overriding royalty payments reflecting higher production at ERT's Wang well.

Income Tax Provision. Income taxes reflected expenses of $29.8 million in the three-month period ended September 30, 2014 as compared to $7.1 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 28.3% for the three-month period ended September 30, 2014 was higher than the 13.5% effective tax rate for the same period in 2013 as a result of projected year-over-year increases in profitability in the United States and the 2013 tax benefit of a reduction in the U.K. statutory tax rate (Note 7).

Comparison of Nine Months Ended September 30, 2014 and 2013

The following table details various financial and operational highlights for the periods presented (dollars in thousands):

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Increase/ (Decrease)
Net revenues —			
Well Intervention	$ 546,057	$ 319,893	$ 226,164
Robotics	339,301	242,940	96,361
Subsea Construction	358	69,305	(68,947)
Production Facilities	71,373	68,933	2,440
Intercompany elimination	(57,093)	(51,347)	(5,746)
	$ 899,996	$ 649,724	$ 250,272
Gross profit —			
Well Intervention	$ 205,498	$ 101,887	$ 103,611
Robotics	75,230	38,000	37,230
Subsea Construction	403	15,439	(15,036)
Production Facilities	33,583	40,420	(6,837)
Corporate and other	(2,433)	(3,687)	1,254
Intercompany elimination	(1,050)	(2,538)	1,488
	$ 311,231	$ 189,521	$ 121,710
Gross margin —			
Well Intervention	38 %	32 %	
Robotics	22 %	16 %	
Subsea Construction	113 %	22 %	
Production Facilities	47 %	59 %	
Total company	35 %	29 %	

Number of vessels (1) / Utilization (2)				
Well Intervention vessels	5/95	%	4/91	%
ROVs	63/77	%	57/61	%
Robotics vessels	6/87	%	5/89	%
Subsea Construction vessels	N/A		0/92	%

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

Table of Contents

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in each category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues are as follows (in thousands):

	Nine Months Ended September 30, 2014	2013	Increase/ (Decrease)
Well Intervention	$ 22,052	$ 15,052	$ 7,000
Robotics	35,041	31,305	3,736
Subsea Construction	—	317	(317)
Production Facilities	—	4,673	(4,673)
	$ 57,093	$ 51,347	$ 5,746

Intercompany segment profit is as follows (in thousands):

	Nine Months Ended September 30, 2014	2013	Increase/ (Decrease)
Well Intervention	$ (236)	$ (91)	$ (145)
Robotics	1,417	2,602	(1,185)
Subsea Construction	—	158	(158)
Production Facilities	(131)	(131)	—
	$ 1,050	$ 2,538	$ (1,488)

Net Revenues. Our total net revenues increased by 39% for the nine-month period ended September 30, 2014 as compared to the same period in 2013. Net revenues for our business segments increased in the comparable year over year periods, reflecting the addition of vessels in our Well Intervention business, the increased number of assets and asset utilization within our Robotics segment, and the slightly higher revenues for the HP I reflecting the variable production component of the fee arrangement in the Phoenix field. Our Subsea Construction revenues decreased reflecting the sale of our pipelay vessels in mid-year 2013.

Our Well Intervention revenues increased by 71% for the nine-month period ended September 30, 2014 as compared to the same period in 2013 reflecting the addition of a chartered vessel, the Skandi Constructor, in April 2013 and the Helix 534 being placed in service in the Gulf of Mexico in February 2014. Our vessels had high utilization (95%) during the first nine months of 2014 with the primary exception being the Well Enhancer that went into regulatory dry dock in mid-December 2013 and returned to service in late January 2014. The Skandi Constructor and the Seawell are currently scheduled for dry dock in the fourth quarter of 2014. The Skandi Constructor is scheduled for its normal regulatory dry dock in November 2014, which should take approximately one month to complete. The Seawell is scheduled for both normal regulatory dry dock and certain capital upgrades during its dry dock, which is scheduled to commence in December 2014 and expected to last approximately four months in duration. Upgrades to the Seawell are intended to extend the vessel's useful economic life.

Robotics revenues increased by 40% for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The increase primarily reflects the addition of five ROVs and one trencher to our fleet, the higher utilization of our ROVs and trenchers, and 300 additional days of spot vessel utilization. Our trenching activities, primarily conducted in the North Sea region, have significantly increased during 2014 as compared to the unusually weak market that was experienced in 2013.

Table of Contents

Our Production Facilities revenues increased by 4% for the nine-month period ended September 30, 2014 as compared to the same period in 2013, which reflects an increase in our total revenues under our fee arrangement for the HP I, including the variable portion of the fee for throughput processed by the HP I. The quarterly HFRS retainer fees also increased effective April 1, 2013 as a result of new four-year agreements.

Gross Profit. Our total gross profit increased by 64% for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The gross profit associated with our Well Intervention segment increased by 102% for the nine-month period ended September 30, 2014 as compared to the same period in 2013 reflecting the addition of two vessels to our fleet since March 31, 2013.

The gross profit associated with our Robotics segment increased by 98% for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The variance primarily reflects increased utilization for our ROVs and trenching assets and related support vessels. Utilization for our trenching assets increased significantly reflecting the resumption of trenching projects in the North Sea region following an unusually weak year for that work in 2013.

The gross profit related to our Production Facilities segment decreased by 17% for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The decrease primarily reflects the amortization of the deferred regulatory dry dock costs for the HP I that were incurred during the fourth quarter of 2013.

Loss on Commodity Derivative Contracts. In December 2012, following the announcement of the sale of ERT, we de-designated our oil and gas commodity derivative contracts and interest rate swap contracts as hedging instruments (Note 15). The $14.1 million loss on commodity derivative contracts reflects the net loss on our oil and gas commodity derivative contracts during the first quarter of 2013. In February 2013, we paid approximately $22.5 million to settle our remaining open commodity derivative contracts.

Gain on Disposition of Assets, Net. The $10.4 million net gain on disposition of assets for the nine-month period ended September 30, 2014 primarily reflects a $10.5 million gain associated with the sale of our Ingleside spoolbase in January 2014. The $14.7 million gain on disposition of assets for the nine-month period ended September 30, 2013 primarily reflects a $1.1 million loss on the sale of the Caesar in June 2013 and a $15.6 million gain on the sale of the Express in July 2013.

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $4.6 million for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The increase primarily reflects $5.2 million of charges associated with the provision for uncertain collection of a portion of our existing trade receivables (Note 13).

Equity in Earnings of Investments. Equity in earnings of investments decreased by $1.4 million for the nine-month period ended September 30, 2014 as compared to the same period in 2013. The decrease primarily reflects lower revenues for both Deepwater Gateway and Independence Hub reflecting lower production at the fields being processed at each facility. Additionally, Deepwater Gateway's operations were affected by a fire at the facility in early May 2014 that shut in production at the platform for most of the second quarter. Production was restored to the facility in July 2014.

Net Interest Expense. Our net interest expense totaled $12.9 million for the nine-month period ended September 30, 2014 as compared to $28.3 million for the same period in 2013. The decrease consists of both a reduction in interest expense and increases in interest income and capitalized interest. The decrease in interest expense reflects the substantial reduction in our indebtedness, including the $318.4 million repayment of debt in February 2013 following the sale of ERT and our redemption in July 2013 of the remaining $275 million of our Senior Unsecured Notes then outstanding. Interest income totaled $4.1 million for the nine-month period ended September 30, 2014 as compared to $0.9 million for the same period in 2013. The amount of interest income for the first nine months of 2014 includes $2.1 million from an IRS income tax refund (Note 7) and $1.4 million on the promissory note held in connection with the sale of our Ingleside spoolbase (Note 3). Capitalized interest totaled $7.5 million for the first nine months of 2014 as compared to $6.8 million for the first nine months of 2013. Generally, our capitalized interest will be increasing as the construction of our vessels and related equipment progresses.

Table of Contents

Loss on Early Extinguishment of Long-term Debt. The $12.1 million loss in the nine-month period ended September 30, 2013 included the $8.6 million loss in connection with our redemption in July 2013 of the remaining $275 million Senior Unsecured Notes then outstanding and the acceleration of the remaining $3.5 million of deferred financing fees related to the term loan component of our former credit agreement following the repayments of indebtedness and the related termination of the facility.

Other Expense, Net. We reported net other expense of $0.2 million for the nine-month period ended September 30, 2014 as compared to $1.9 million for the same period in 2013. These amounts primarily reflect foreign exchange fluctuations in our non-U.S. dollar functional currencies. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange losses was $0.7 million related to our foreign exchange forward contracts in the nine-month period ended September 30, 2013 (Note 15).

Other Income – Oil and Gas. The $15.7 million income for the nine-month period ended September 30, 2014 includes a $7.2 million insurance reimbursement related to asset retirement work previously performed with the remaining income associated with our overriding royalty interests in ERT's Wang well, which commenced production in late April 2013. The $5.8 million income for the nine-month period ended September 30, 2013 primarily represents cash payments related to services we provided to ERT following its sale to a third party and the initial proceeds associated with our overriding royalty interests in ERT's Wang well.

Income Tax Provision. Income taxes reflected expenses of $67.8 million in the nine-month period ended September 30, 2014 as compared to $16.1 million in the same period last year. The variance primarily reflects increased profitability in the current year period. The effective tax rate of 26.5% for the nine-month period ended September 30, 2014 was higher than the 17.7% effective tax rate for the same period in 2013 as a result of projected year-over-year increases in profitability in the United States and the 2013 tax benefit of a reduction in the U.K. statutory tax rate (Note 7).

Oil and Gas

All of our oil and gas assets sold in February 2013 were located in the U.S. Gulf of Mexico. The operating results of our discontinued oil and gas operations during 2013 are presented in our Quarterly Report on Form 10-Q for the three-month period ended March 31, 2013. Our continuing operations include one oil and gas property located offshore of the United Kingdom ("U.K."). During the first quarter of 2013, we recorded a $1.6 million charge reflecting the estimated final costs to complete our U.K. property's abandonment activities. We completed the reclamation activities for this offshore property in 2013 in accordance with applicable U.K. regulations.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain useful information in the analysis of our financial condition and liquidity (in thousands):

	September 30, 2014	December 31, 2013
Net working capital	$ 575,841	$ 553,427
Long-term debt (1)	$ 529,281	$ 545,776
Liquidity (2)	$ 1,129,699	$ 1,062,413

(1) Long-term debt does not include the current maturities portion of our long-term debt as that amount is included in net working capital. It is also net of unamortized debt discount on the 2032 Notes. See Note 6 for information related to our existing debt.

Table of Contents

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by letters of credit drawn against the facility. As of September 30, 2014, our liquidity included cash and cash equivalents of $546.5 million and $583.2 million of available borrowing capacity under our Revolving Credit Facility (Note 6). As of December 31, 2013, our liquidity included cash and cash equivalents of $478.2 million and $584.2 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our long-term debt, including current maturities, is as follows (in thousands):

	September 30, 2014	December 31, 2013
Term Loan (matures June 2018)	$ 281,250	$ 292,500
2032 Notes (mature March 2032) (1)	177,633	173,484
MARAD Debt (matures February 2027)	94,792	100,168
Total debt	$ 553,675	$ 566,152

(1) Amounts are net of the unamortized debt discount of $22.4 million and $26.5 million, respectively. The 2032 Notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 15, 2018, which is the first date on which the holders of the notes may require us to repurchase the notes.

The following table provides summary data from our condensed consolidated statements of cash flows (in thousands):

	Nine Months Ended September 30, 2014	2013
Cash provided by (used in):		
Operating activities	$ 301,561	$ 50,309
Investing activities	$ (208,498)	$ (80,771)
Financing activities	$ (25,982)	$ (477,623)
Discontinued operations (1)	$ —	$ 552,462

(1) Represents total cash flows associated with the operations of ERT. ERT was sold in February 2013. Proceeds from the sale of ERT totaled $614.8 million, net of transaction costs. Other cash flows in the table above reflect our continuing operations.

Our current requirements for cash primarily reflect the need to fund capital expenditures for the growth of our current lines of business and to service our debt. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We have a reasonable basis for estimating our future cash flows supported by our existing and expanding backlog. We believe that internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months.

In accordance with our Credit Agreement, the 2032 Notes, the MARAD Debt agreements, and the Nordea Credit Agreement, we are required to comply with certain covenants, including certain financial ratios such as a consolidated interest coverage ratio and consolidated leverage ratio, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD Debt and our Nordea Credit Agreement indebtedness) secured by the underlying asset, provided that indebtedness is not guaranteed by us. The Credit Agreement also permits our Unrestricted Subsidiaries to incur indebtedness provided that it is not guaranteed by us or any of our Restricted Subsidiaries. As of September 30, 2014 and December 31, 2013, we were in compliance with all of our debt covenants.

Table of Contents

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, that failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by our lenders, including foreclosure against our collateral.

In July 2013, we borrowed $300 million under our Term Loan in connection with our early redemption of the remaining $275 million Senior Unsecured Notes then outstanding. We may borrow and/or obtain letters of credit up to $600 million under our Revolving Credit Facility. Subject to customary conditions, we may request that aggregate commitments with respect to the Revolving Credit Facility be increased by, or additional term loans be made of, or a combination thereof, up to $200 million. See Note 6 for additional information relating to our long-term debt, including more information regarding our current and former credit agreements, including covenants and collateral.

The 2032 Notes can be converted to equity prior to their stated maturity upon certain triggering events specified in the Indenture governing the notes. Beginning in March 15, 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to repurchase them. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our condensed consolidated balance sheet. No conversion triggers were met during the nine-month periods ended September 30, 2014 and 2013.

Operating Cash Flows

Total cash flows from operating activities increased by $281.8 million in the nine-month period ended September 30, 2014 as compared to the same period in 2013. This increase primarily reflects increases in income from operations, changes in working capital, and a $35.2 million IRS income tax refund we received in September 2014. Operating cash flows for the nine-month period ended September 30, 2013 also included $30.5 million of net cash used in discontinued operations related to ERT, which was sold in February 2013.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, improvements and modifications to existing assets, and investments in our production facilities. Significant sources (uses) of cash associated with investing activities are as follows (in thousands):

	Nine Months Ended September 30,	
	2014	2013
Capital expenditures:		
Well Intervention	$ (167,227)	$ (245,105)
Robotics	(36,287)	(29,514)
Production Facilities	(769)	(504)
Other	(245)	(812)
Distributions from equity investments, net (1)	5,041	6,110
Proceeds from sale of assets (2)	11,074	189,054
Acquisition of noncontrolling interests (3)	(20,085)	—
Net cash used in investing activities – continuing operations	(208,498)	(80,771)
Oil and Gas capital expenditures	—	(31,855)
Proceeds from sale of ERT, net of transaction costs	—	614,820
Net cash provided by investing activities – discontinued operations	—	582,965

Net cash provided by (used in) investing activities	$	(208,498)	$	502,194

Table of Contents

(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments for the nine-month periods ended September 30, 2014 and 2013 were \$5.8 million and \$8.3 million, respectively (Note 5).

(2) Primarily reflects cash received from the sale of our two remaining pipelay vessels in mid-year 2013 and from the sale of our Ingleside spoolbase in January 2014.

(3) Relates to the acquisition in February 2014 of our former minority partner's noncontrolling interests in the entity that owns the HP I (Note 2).

Capital expenditures associated with our business primarily include payments associated with the construction of the Q5000 and the Q7000 (see below), payments in connection with the acquisition and subsequent upgrades to and modifications of the Helix 534 (see below), and the costs incurred in the acquisition of additional ROVs and trenchers related to our robotics operations.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semi-submersible well intervention vessel, the Q5000. This \$386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Pursuant to the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At September 30, 2014, our total investment in the Q5000 was \$282.0 million, including \$231.9 million of scheduled payments made to the shipyard. We plan to incur approximately \$69 million on the Q5000 over the remainder of 2014, including a \$58 million shipyard payment. The vessel is expected to be completed and placed in service in early 2015. In September 2014, we entered into the Nordea Credit Agreement to partially finance the construction of the Q5000 and other future capital projects. The Nordea Term Loan will be funded at or near the time of the delivery of the Q5000 (Note 6).

In September 2013, we executed a second contract with the same shipyard in Singapore that is currently constructing the Q5000. This contract provides for the construction of a newbuild semi-submersible well intervention vessel, the Q7000, which will be built to North Sea standards. This \$346.0 million shipyard contract represents the majority of the expected costs associated with the construction of the Q7000. Pursuant to the terms of this contract, 20% of the contract price was paid upon the signing of the contract and the remaining 80% will be paid upon the delivery of the vessel, which is expected to occur in 2016. At September 30, 2014, our total investment in the Q7000 was \$95.7 million, including \$69.2 million paid to the shipyard upon signing the contract. We plan to incur approximately \$8 million on the Q7000 over the remainder of 2014.

In February 2014, we entered into agreements with Petrobras to provide well intervention services offshore Brazil. The initial term of the agreements with Petrobras is for four years with options to extend. In connection with the Petrobras agreements, we entered into charter agreements with Siem Offshore AS for two newbuild monohull vessels, both of which are expected to be in service for Petrobras in 2016. Our total investment in the topside equipment for both vessels is expected to be approximately \$260 million. We have invested \$31.0 million as of September 30, 2014 and plan to invest approximately \$14 million in the topside equipment over the remainder of 2014.

Net cash used in discontinued operations relates to capital expenditures associated with ERT. Oil and Gas capital expenditures for the first quarter of 2013 included costs associated with the exploration and development activities primarily related to the Wang well within the Phoenix field at Green Canyon Block 237.

Outlook

We anticipate that our total capital expenditures for 2014 will be approximately $385 million. This estimate may increase or decrease based on various economic factors and/or the existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that our cash on hand, internally-generated cash flows, and availability under our credit facility will provide the capital necessary to continue funding our 2014 initiatives.

Table of Contents

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of September 30, 2014 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2032 Notes (2)	$200,000	$—	$—	$—	$200,000
Term Loan (3)	281,250	18,750	60,000	202,500	—
MARAD debt	94,792	5,644	12,148	13,390	63,610
Interest related to debt	191,220	24,964	44,090	27,281	94,885
Property and equipment (4)	573,175	274,527	298,648	—	—
Operating leases (5)	1,061,217	136,455	329,323	264,753	330,686
Total cash obligations	$2,401,654	$460,340	$744,209	$507,924	$689,181

(1) Excludes unsecured letters of credit outstanding at September 30, 2014 totaling $16.8 million. These letters of credit guarantee items such as various contractual obligations, customs duties, contract bidding and insurance activities.

(2) Notes mature in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of our common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of its issuance price on that 30th trading day (i.e., $32.53 per share). At September 30, 2014, the conversion trigger was not met. The first date that the holders of these notes may require us to repurchase the notes is March 15, 2018. See Note 6 for additional information.

(3) Amount reflects borrowings made in July 2013. The Term Loan will mature on June 19, 2018.

(4) Primarily reflects the costs associated with our well intervention assets currently under construction, including our new semi-submersible well intervention vessels, the Q5000 and the Q7000, and the topside equipment for the two newbuild monohull vessels that we plan to charter (Note 12).

(5) Operating leases include vessel charters and facility leases. At September 30, 2014, our vessel charter and ROV lease commitments totaled approximately $1.0 billion, including four vessels that will not be delivered to us until 2015 and 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements. We prepare these financial statements and related footnotes in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. For additional information regarding our critical accounting policies and estimates, please read our "Critical Accounting Policies and Estimates" as disclosed in our 2013 Form 10-K.

40

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: interest rates and foreign currency exchange rates.

Interest Rate Risk. As of September 30, 2014, $281.3 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in September 2013, we entered into interest rate swap contracts to fix the interest rate on $148.1 million of our Term Loan. These swap contracts, which are settled monthly, began in October 2013 and extend through October 2016. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $1.1 million in interest expense for the nine-month period ended September 30, 2014.

Foreign Currency Exchange Rate Risk. Because we operate in various regions around the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to our North Sea operations). As such, our earnings are subject to movements in foreign currency exchange rates when transactions are denominated in (i) currencies other than the U.S. dollar, which is our functional currency, or (ii) the functional currency of our subsidiaries, which is not necessarily the U.S. dollar. In order to mitigate the effects of exchange rate risk in areas outside the United States, we generally pay a portion of our expenses in local currencies and a substantial portion of our contracts provide for collections from customers in U.S. dollars. During the nine-month period ended September 30, 2014, we recognized losses of $0.2 million related to foreign currency transactions in “Other expense, net” in our condensed consolidated statement of operations.

We also entered into various foreign currency exchange contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds and Norwegian kroners. In January 2013, we entered into foreign currency exchange contracts to hedge through September 2017 the foreign currency exposure associated with the Grand Canyon charter payments ($104.6 million) denominated in Norwegian kroner (NOK591.3 million). In February 2013, we entered into similar foreign currency exchange contracts to hedge our foreign currency exposure with respect to the Grand Canyon II and the Grand Canyon III charter payments ($100.4 million and $98.8 million, respectively) denominated in Norwegian kroner (NOK594.7 million and NOK595.0 million, respectively), through July 2019 and February 2020, respectively. These contracts currently qualify for hedge accounting treatment. All of our remaining foreign exchange contracts that were not accounted for as hedge contracts have been settled. We had no foreign currency exchange contracts for vessel charters denominated in British pounds as of September 30, 2014 (Note 15).

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as of the end of the fiscal quarter ended September 30, 2014. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 2014 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 12 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum number of shares that may yet be purchased under the program (2)
July 1 to July 31, 2014	—	$ —	—	7,448
August 1 to August 31, 2014	—	—	—	7,448
September 1 to September 30, 2014	72,140	26.12	72,140	—
	72,140	$ 26.12	72,140	

(1) Includes shares delivered to the Company by employees in satisfaction of minimum withholding taxes upon vesting of restricted shares.

(2) Under the terms of our stock repurchase program, the issuance of shares to members of our Board of Directors and to certain employees, including shares issued to our employees under the Employee Stock Purchase Plan (the "ESPP") (Note 10), increases the amount of shares available for repurchase. The shares purchased include the ESPP shares issued to our employees in September 2014. For additional information regarding our stock repurchase program, see Note 11 to our 2013 Form 10-K.

Item 6. Exhibits

The exhibits to this report are listed in the Exhibit Index beginning on Page 44 hereof.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	HELIX ENERGY SOLUTIONS GROUP, INC. (Registrant)
Date: October 22, 2014	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: October 22, 2014	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Table of Contents

INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of Helix.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Credit Agreement dated September 26, 2014, by and among Helix Q5000 Holdings S.à r.l., Helix Vessel Finance S.à r.l. and Nordea Bank Finland PLC, London Branch as administrative agent and collateral agent, together with the other lenders party thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on September 30, 2014 (001-32936)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	Filed herewith
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith